TS 6401

METHOD OF DETERMINING A FLUID INFLOW PROFILE ALONG THE
LENGTH OF A PERMEABLE INFLOW REGION OF AN UNDERGROUND
WELLBORE

The present application claims priority on European
Application 03104972.9 filed 24 December 2003.

FIELD OF THE INVENTION

The invention relates to a method of determining a
fluid inflow profile along the length of a permeable
inflow region of an underground wellbore.

5   BACKGROUND OF THE INVENTION

Temperature logs have been used for many years in the
oil and gas industry to obtain inflow and outflow
information of selected intervals. US patent 4,520,666
discloses a method of determining inflow into a well by
10   determining the temperature in the well along the length
of the inflow region by moving a logging sonde which is
equipped with a temperature sensor up and/or down through
the well inflow region.

More recently fiber optic Distributed Temperature
15   Sensing (DTS) systems have become available to obtain
temperature profiles along a well on a permanent basis.
International patent application WO 01/04581 discloses
the use of a fiber optic DTS sensor to determine the mass
flow rates of produced fluids in a wellbore.

20   The temperature profile in an oil and/or gas
production well is based on the difference between the
geothermal gradient along the well and the inflowing
fluids. In vertical or deviated wells a temperature
contrast develops if two or more zones at different
25   depths produce to the well. This temperature contrast is
a function of the reservoir depth, the geothermal

gradient and the thermal properties of the fluid and the
well (casing, cement).

In a horizontal inflow region of an oil and/or gas
productions well there is no geothermal gradient along
the horizontal section. Differences can only be caused
either by cooling due to gas expansion, known as the
Joule Thompson effect, which occurs in gas reservoirs or
oil reservoirs where gas comes out of solution during
production, or when water is produced from a deeper
aquifer (potential higher temperature) or from a nearby
water injector (potential lower temperature).

International patent application WO 00/11317 and
US patent 6,497,279 disclose methods of monitoring
production in an oil production well by means of an
electrical heater cable and adjacent fiber optical DTS
sensor, wherein the wellbore is heated by the electrical
heater cable during production and the fluid flow is
determined from the temperature profile measured by the
fiber optical DTS sensor on the assumption that the fluid
flowing from the formation to the wellbore lowers the
temperature in the wellbore at the inflow locations.

US patent application US 2003/0140711 discloses a
method for monitoring the velocity of fluids in a well
wherein a point near the lower end of the well is cooled
during a well shut in and the upward velocity of the cold
spot is measured after restarting production by a fibre
optical temperature sensing cable that extends along the
length of the wellbore.

SUMMARY OF THE INVENTION

The present invention include a method for
determining a fluid inflow profile along the length of a
permeable inflow region of an underground wellbore
comprises the steps of:

–   transferring heat into or from the permeable inflow
region of the wellbore during a well shut in period such
that at least a substantial part of the inflow region has
a temperature which is different from the temperature of
5   the surrounding formation;
–   starting production of hydrocarbon fluids via said
permeable inflow region;
–   measuring substantially simultaneously the
temperature of the fluids at various points along at
10   least part of the length of the inflow region;
–   determining at selected intervals of time after
production start up a temperature profile along at least
part of the length of the inflow region on the basis of
the thus measured temperatures ; and
15   –   determining a fluid inflow profile along the length
of said inflow region on the basis of a comparison of the
determined temperature profiles at selected intervals
after production start up, wherein at least a substantial
part of the permeable inflow region is heated during the
20   well shut-in period and wherein during an initial period
of time after starting production of hydrocarbons via
said permeable inflow region heating of the permeable
inflow region is continued and wherein during a
subsequent period of time following said initial period
25   heating of the permeable inflow region is interrupted,
and the temperature is measured both during said initial
and subsequent periods of time and wherein differences
between the temperature variation over time measured
during said initial and subsequent period are used to
30   determine a heat capacity of the inflowing fluid.

The level of temperature variation per unit of time,
such as the local heat up or cool down rate, may be used

as an indicator of the level of influx of fluid at
various points along the length of said inflow region.

In case during a shut in, when no fluids flow into
the well, a well inflow region is heated by an electrical
heater cable which has a substantially constant
electrical resistance along the length of the heated
section this will result in an substantially constant
increase in well temperature over time along the heated
section. When the well is put back on production the
zones with relatively high flow rates will cool down to
reservoir temperature faster than zones with no or little
fluid flow.

Accordingly, the inflow profile may be determined
such that if at a specific location the measured
temperature variation over time is higher than at
adjacent locations along the length of the permeable
inflow region the thus measured peak in the temperature
variation per unit of time is used as an indicator that
at said specific location the influx of fluids is higher
than at said adjacent locations, whereas if at another
specific location the measured temperature variation per
unit of time is lower than at adjacent locations along
the length of the permeable inflow region the thus
measured dip in the temperature variation per unit of
time is used as an indicator that at said other specific
location the influx of fluids is lower than at said
adjacent locations.

In the method according to the invention a ratio of
the temperature variation over time measured during the
initial period and during the subsequent period is
determined for various points along the length of the
inflow region and said ratio is used as an indicator of
the heat capacity of the fluid flowing into the well.

More particularly, a relatively high ratio between the
temperature variation measured during the initial and
subsequent periods may be used as an indicator that the
inflowing fluid has a relatively low heat capacity and a
relatively high gas content.

The permeable inflow region may be heated by an
electrical heater cable extending along at least a
substantial part of the length of the permeable inflow
region and the temperature may be measured by means of a
fiber optical distributed temperature sensor (DTS)
extending along at least a substantial part of the length
of the permeable inflow region.

The fiber optical distributed temperature sensor
(DTS) may be strapped to the outer surface of the
electrical heater cable.

Alternatively, the electrical heater cable may
comprise an electrical conductor, which is surrounded by
a mineral insulation layer comprising a compacted mineral
powder, which is enclosed in an annular metal sheath, and
the fiber optical sensor is embedded in a channel
extending through the mineral insulation layer.

The invention also relates to a method of producing
crude oil from a subterranean formation, wherein the
influx of crude oil and/or other fluids into the well is
determined and/or adjusted to an optimal level on the
basis of the method according to the invention.

The invention furthermore relates to heater and
distributed temperature sensing (DTS) system suitable for
use in the method according to the invention. The system
comprises one or more mineral insulated heater cables,
which each comprise an electrical conductor which is
surrounded by a mineral insulation layer comprising an
compacted mineral powder, which layer is enclosed in an

annular metal sheath, and a fiber optical distributed
temperature sensor which extends along at least a
substantial part of the length of one or more mineral
insulated heater cables.

5   Optionally at least one fiber optical distributed
temperature (DTS) sensor extends through a channel
extending through the mineral insulation layer of at
least one of the mineral insulated heater cables.

BRIEF DESCRIPTION OF THE DRAWINGS

10   The method according to the invention will be
described in more detail with reference to the
accompanying drawings in which:

        Figure 1 illustrates a suitable configuration of a
Distributed Temperature Sensing (DTS) optical fiber
15   assembly;

        Figure 2 shows a typical spectrum of light
backscattered from different points along the length of
the fiber, which spectrum carries information about the
temperature along the length of the fiber;

20   Figure 3 is a schematic longitudinal sectional view
of an oil and/or gas production well in which a MI heater
cable with integrated DTS optical fiber assembly is
arranged;

        Figure 4 is a cross-sectional view, at an enlarged
25   scale, of the horizontal inflow region and MI heater
cable with integrated DTS optical fiber assembly taken
along line IV-IV in Fig.3 and seen in the direction of
the arrows; and

        Figure 5 is a graph which illustrates the results of
30   a simulated application of the method according to the
invention in an oil and/or gas production well , which
has an inflow region where the surrounding oil/and or gas
reservoir has three zones of different permeability.

DETAILED DESCRIPTION

Distributed Temperature Sensing (DTS) with optical
fibers is based on optical time-domain reflectometry.
Figure 1 illustrates the principle of DTS operation. A
5   pulsed laser 2 is coupled to an optical fiber 1 that is
the sensing element. The light is backscattered as the
pulse propagates through the fiber 1 owing to density and
composition as well as to molecular and bulk vibrations.
A portion of the backscattered light is guided back to
10   the light source 2 and split of by a directional
coupler 3 to a receiver 4. Under ideal conditions the
intensity of the backscattered light decays exponentially
with time. As the speed of light within the fiber 1 is
known, the distance that the light has passed through the
15   fiber 1 can be derived from the time along the decay
curve.

Figure 2 illustrates that the backscattered light
includes different spectral components which contain
peaks that are known as Rayleigh and Brillouin peaks and
20   Raman bands. The Rayleigh peak 5 is independent of
temperature but is useful in identifying breaks and
inhomogeneities along the fiber. The Raman spectral
bands 6 are caused by thermally influenced molecular
vibrations. These are naturally occurring phenomena in
25   glass as well as in fluids, gases and solids. The Raman
spectral bands 6 can be used to obtain information about
distribution of temperature along the well.

The Raman backscattered light has two components,
Stokes 6A and Anti-Stokes 6B, one being only weakly
30   dependent on temperature and the other being greatly
influenced by temperature. The relative intensities
between the Stokes and Anti-Stokes components 6A and 6B
are a function of temperature at which the backscattering

occurred. Therefore, temperature can be determined at any
point along the length of the optical fiber 1 by
comparing at each point the Stokes and Anti-stokes
components 6A and 6B of the light backscattered from the
5   particular point. The Brillouin peaks 7 may be used to
monitor strain along the length of the optical fiber 1.

The level of temperature variation per unit of time,
such as the local heat up or cool down rate, may used as
an indicator of the level of influx of fluid at various
10   points along the length of said inflow region.

In case during a shut in, when no fluids flow into
the well, a well inflow region is heated by an electrical
heater cable which has a substantially constant
electrical resistance along the length of the heated
15   section this will result in an substantially constant
increase in well temperature over time along the heated
section. When the well is put back on production the
zones with relatively high flow rates will cool down to
reservoir temperature faster than zones with no or little
20   fluid flow.

Accordingly, the inflow profile may be determined
such that if at a specific location the measured
temperature variation over time is higher than at
adjacent locations along the length of the permeable
25   inflow region the thus measured peak in the temperature
variation per unit of time is used as an indicator that
at said specific location the influx of fluids is higher
than at said adjacent locations, whereas if at another
specific location the measured temperature variation per
30   unit of time is lower than at adjacent locations along
the length of the permeable inflow region the thus
measured dip in the temperature variation per unit of
time is used as an indicator that at said other specific

location the influx of fluids is lower than at said
adjacent locations.

   In the method according to the invention a ratio of
the temperature variation over time measured during the
initial period and during the subsequent period is
determined for various points along the length of the
inflow region and said ratio is used as an indicator of
the heat capacity of the fluid flowing into the well.
More particularly, a relatively high ratio between the
temperature variation measured during the initial and
subsequent periods may be used as an indicator that the
inflowing fluid has a relatively low heat capacity and a
relatively high gas content.

   The permeable inflow region may be heated by an
electrical heater cable extending along at least a
substantial part of the length of the permeable inflow
region and the temperature may be measured by means of a
fiber optical distributed temperature sensor (DTS)
extending along at least a substantial part of the length
of the permeable inflow region.

   The fiber optical distributed temperature sensor
(DTS) may be strapped to the outer surface of the
electrical heater cable.

   Alternatively, the electrical heater cable may
comprise an electrical conductor, which is surrounded by
a mineral insulation layer comprising a compacted mineral
powder, which is enclosed in an annular metal sheath, and
the fiber optical sensor is embedded in a channel
extending through the mineral insulation layer.

   Figure 3 shows how an optical DTS fiber 1 is arranged
in the horizontal inflow region 10 and the vertical riser
section of a well 11. The well 11 is equipped with a
0.6 cm (¼ inch) OD control line 12 through which a

Mineral Insulated (MI) heater cable 13 and lead in
cable 19 extend. This control line 12 may be installed
either outside or inside the well casing 20, liners
and/or perforated sandscreen 22 in the horizontal inflow
5   region 10 of the well 11. Electrical power is supplied to
the lead in cable 19 by an electrical power supply
source 21. Pulsed laser light signals are supplied to the
optical fiber 1 by the laser light source 2 and the light
spectrum backscattered from different points along the
10   length of the optical fiber 1 is reflected by a
directional coupler 3 to a receiver 4. The receiver 4 is
equipped with a light processing unit in which in
particular the Stokes and anti-Stokes Raman bands 6A and
6B of the backscattered light are converted into a signal
15   which is related to the temperature of the optical
fiber 1 at the point where the light pulse has been
reflected in accordance with the description provided
with reference to Figures 1 and 2.

The mineral insulated (MI) heater cable 13 is made up
20   of an outer metal sheath 14, usually cylindrical, that
contains a concentric solid metal rod 15. The annular
space between the sheath 14 and the metal rod 15 is
filled with an insulant 16, usually in powder form, that
is a good electrical insulator and a reasonable thermal
25   conductor. The metal rod 15 or core is used to conduct a
current, usually AC, which generates heat by ohmic
dissipation. The MI heater cables 13 may be operated
under DC conditions or under AC single-phase or AC three-
phase conditions. The length of the MI heater cables 13
30   can vary from 15 to 1000 m. For monitoring influx into an
oil production well a suitable length along with the well
inflow region is heated may be about 250 m.

The MI heater cable 13 may be configured to deliver
between 0 and 1 KW/m with larger powers easily achieved
for shorter heater cables. The power level is such that
the core temperature must not exceed a maximum value
5   related to the breakdown strength of the insulant 16 and
the sheath temperature must not exceed a maximum
temperature related to the corrosion resistance of the
sheath alloy. This means that the core temperature is in
the 650 to 870 Degrees Celsius (1200 °F to 1600 °F) range
10   and the sheath temperature in the 540 to 760 Degrees
Celsius (1000 °F to 1400 °F) range.

The heater assembly may consist of one or multiple MI
heater cables 13 placed in the well. The heater(s) can
support its (or their) own weight if the sheath
15   temperature is less than 540 Degrees Celsius (1000 °F).
This temperature could be higher with more creep
resistant alloys. The MI heater cables 13 can also be
strapped to a support tube or support cable. A suitable
mode is to have three heater cables strapped to a support
20   and operated with 60-cycle AC voltage in a three-phase Y
configuration.

The DTS optical fiber 1 may extend through a
channel 18 in the insulant 16 of a MI heater cable 13 as
illustrated in Fig. 3 and 4 or may be installed
25   separately from the MI heater cable or cables 13, such as
by strapping a guide tube containing the fiber 1 to the
outer surface of MI heater cable 13 or to the support
tube or support cable. The guide tube may be U-shaped
such that a double-ended optical fiber can be injected
30   into the guide tube after installation of the guide tube
in the well 11 and/or to replace a damaged optical
fiber 1.

The heater assembly is configured such that the
voltage between the central metal rod 15 and sheath 14 is
substantially below the breakdown voltage of the
insulant 16 at the expected operating temperature of the
5   heater. The sheath alloy has to have a low enough
corrosion rate such that a substantially low fraction of
its thickness is negatively affected by corrosion over
the lifetime required of the heater. The mechanical
strength of the heater assembly is sufficient to avoid
10   elongation damage to the MI heater cables 13 when
suspended vertically in the well. For most of the
applications in DTS measurements these conditions should
be satisfied. Suitable embodiments for the various
components of the MI heater cable 13 are described in
15   more detail below.

The sheath 14 is a metallic tubular that forms the
outer part of the MI heater cable 13. The sheath 14
material will be in contact with formation fluids. Its
metallurgy has to be good enough to resist corrosion in
20   the heated formation environment. Alloys that can be used
in the temperature range indicated include SS 304,
SS 310, Incoloy 800 and Inconel 600.

The sheath 14 as well as the cold pins and the
splices described below are devoid of holes that might
25   allow moisture into the insulant 16. Excessive moisture
in the insulant 16 can lead to a drop in insulant
resistivity and/or a chemical change leading again to a
drop in resistivity.

The metal rod 15 is configured to deliver the
30   appropriate power. A given heater can have one or more
metal rods 15 within a single sheath 14 and one or more
than one heater can be strapped together in a bundle
within a well. The power dissipation required per

conductor is equal to the total power dissipation per
well divided by the total number of conductors. In a
suitable configuration three single conductor MI heater
cables 13 are strapped to a support member (not shown).
5   The metal rods 15 of the MI heater cables 13 have a
diameter and a resistivity at operating temperature that
satisfies Ohm's law for the chosen power dissipation per
foot, the length of the heater and the maximum voltage
allowed. Materials that can be used for the metal rods 15
10   include nichrome, nickel, and a number of alloys made
from copper and nickel in increasing nickel
concentrations from pure copper to Alloy 30, Alloy 60,
Alloy 180 and Monel. Nickel-copper alloys are preferred
because they have a lower temperature resistivity
15   coefficient than the pure metals. A preferred material is
Alloy 60. If high power dissipation is required for
shorter length heaters a Nichrome core can be used.

     The insulant 16 may comprise a variety of materials
such as powdered oxides that offer high breakdown
20   strength and high resistivity at the target temperature.
The commonly used powders include MgO, AL_2O_3, Zirconia,
BeO and different chemical variations of Spinels. A
preferred material is MgO. Breakdown voltage and
resistivity are affected by the type and quantity of
25   impurities in the powders and by the porosity of the
powder in the finished heater product. These
characteristics also depend on the method used to
fabricate the heater. Different methods and different
insulants16 may be selected depending on the required
30   temperature and electrical operating characteristics of
the MI heater cable 13. To avoid damage to the MI heater
cable 13 at any hot spots it is preferred that the
finished MI heater cable 13 is configured to withstand at

least 2-3 times the operating voltage at the operating
temperature. Preferably, the MI heater cable 13 is
configured withstand 1000 VAC at the maximum temperature
expected in the well.

Preferred mineral powders for use in the insulant 16
are the "H" mix powder manufactured by Idaho Laboratories
Corporation and the Standard MgO powder used by Pyrotenax
Cable Company for high temperature applications.

The heated section of the heater is normally
connected to a lead-in cable 19 that penetrates the
overburden. The MI heater cable 13 operates at the
maximum temperature required for the DTS measurements
while the lead-in cable 19 is normally rubber insulated
and cannot exceed about 65 Degrees Celsius (150 °F)
(although more expensive lead-in options can be used
either rubber insulated or made from MI cable also). An
economic solution is to place a short transition section
13A of MI cable 13 between the heated section and the
lead-in cable. This transition section 13A of MI cable 13
is made from a less resistive core than the heated
section in order to decrease the power dissipation along
its length and therefore lower its temperature. Alloys of
the type listed above can be used with varying diameters
and the cold pin lengths can vary from 1.5 to 15 m. A
preferred mode is a 10 m cold pin filled with the same
insulant 16 as the heated section. A suitable sheath for
the cold pin is Inconel 600. To inhibit chloride
corrosion cracking in the cold-pin region the sheath 16
of the transition section may comprise Inconel 600 for
corrosion protection of this type. In addition to cold-
pins at the top one might elect to also place cold-pins
at the end of the heated section. This can make the
bottom termination easier to manufacture but adds cost.

The transition from the heated section to the cold
pin has to withstand a temperature equal to half of the
target zone operating temperature at the required
operating voltage. The final density of the insulant in
5   the splice has to be high enough for this purpose.
Preferably the splice is configured to withstand 1000 VAC
at 480 Degrees Celsius (900 °F). High temperature splices
are made by different manufacturers, such as Idaho
Laboratories Corporation or Pyrotenax Cable Company.

10   The end of the cold-pin may be connected to a long
length of flexible rubber insulated copper conductor. The
connection may be a standard epoxy filled small canister
made by the major heater suppliers. This cable is very
similar to typical downhole electrical submersible pump
15   (ESP) cable. Its main characteristic has to be the
ability to withstand maximum overburden temperatures and
be impermeable to the fluid environment in the well.

The heater assembly can be made such that one has one
or several cables powered in parallel with the ends of
20   the cables all at the top. This option called the "hair-
pin" option does not require a bottom termination.

If the heater assembly consists of one or more MI
heater cables 13 in the 3-phase Y configuration they can
be used with no connection at the bottom or with all
25   three-phase cores connected at the bottom. This last
option is preferred. This connection can be made directly
at the end of the heated section or at the end of cold-
pins attached to the end of the heated section, similarly
to the top cold-pins. A preferred mode is to use bottom
30   cold-pins with the three-phase conductors electrically
connected at the end of the bottom cold-pins. This
connection is made within an MgO filled and sealed can or
with an epoxy filled can. A preferred mode is an MgO

filled can using the same MgO as the one used in the
heated section. The final choice of termination will
depend on the space available within the well 11 in
addition to the DTS fiber 1 installed. A suitable
5   MI heater cable configuration is disclosed in
International patent application WO 0183940.

A suitable operational procedure to obtain a
quantitative multi-phase inflow distribution with a
Distributed Temperature System(DTS) optical fiber 1 in
10   combination with a heater assembly comprising one or more
MI heater cables 13 comprises the following five steps:
1. Obtain a steady-state temperature profile under
producing conditions.
2. Shut the well and again obtain a steady-state
15   temperature profile. This profile is representative for
the geothermal gradient and is referred to as a base line
temperature profile.
3. Heat the well at a specified power input and obtain a
steady-state temperature profile. The transient behaviour
20   and the time it takes to get from step 2 to 3 allows the
heat properties in the system to be determined.
4. Put the well back under producing condition with the
heater still on. Obtain a steady-state temperature
profile.
25   5. Turn off the heater and obtain a steady state
temperature profile (the same as the temperature profile
in step 1. The transient behaviour and the time it takes
to get from step 4 to 5 can be used to determine an
inflow distribution for the different phases.
30   Steps 1 and 2 form part of the known procedure for
obtaining temperature data with DTS in order to obtain a
qualitative "single-phase" (total liquid) inflow
distribution.

Steps 3 to 5 are the additional steps required to go
from a qualitative to a quantitative multi-phase
measurement with the use of a heater.

Simulations of the method according to the invention
have been carried out with a thermal reservoir model. In
figure 5, simulated results are shown for a well with a
horizontal section of 600 meters. The horizontal section
has been subdivided into three areas with different
reservoir characteristics, i.e. different permeabilities
of 10, 250 and 100 mD, respectively. Thus, the reservoir
has a decreasing permeability along the well.

The lower horizontal line 30 shows the temperature
profile of a well that is shut-in just before the heater
is activated. The upper horizontal line 31 shows the
temperature profile after 48 hour of heating up the well
with 90 W/m (So about 60 kW for the whole horizontal
sections). After 48 hours the heater is turned off and
the well is put on production. The rest of the
temperature profiles 32-36 show the temperature response
over time. The time it takes for the well to cool down to
the temperature profile 37 prior to shut-in can be
correlated to the inflow from the reservoir.

A physical model that demonstrates that the method
according to the invention can be used to estimate the
velocities and/or composition, such as the watercut, of
the fluids flowing into the well is as follows.

If a fluid is not in thermal equilibrium with the
porous medium it is flowing through, heat will either be
extracted or provided to the medium. The temperature of
the moving fluid changes corresponding to the temperature
of the porous medium and depending on its heat capacity.
The basic equation is

$$\nabla(\nabla T) - \frac{(\rho \cdot c)_f}{\lambda} \cdot \nabla(\vec{v} \cdot T) = 0 \qquad (1)$$

where ∇ is the spatial derivative, T is temperature, ρ is density and c is heat capacity of the fluid, λ is thermal conductivity of the saturated medium, and $\vec{v}$ is the Darcy velocity of the fluid, which can be translated into the actual flow velocity $\vec{V}$ by

$$\vec{V} = \frac{\vec{v}}{\phi} \qquad (2)$$

where ϕ is the porosity.

For one spatial component, e.g. the vertical direction z, the analytic solution to equation (1) is

$$T = T_0 + (T_L - T_0) \cdot \frac{\exp\left\{\frac{z \cdot Pe}{L}\right\} - 1}{\exp\{z \cdot Pe\} - 1} \qquad (3)$$

where T_0 is the temperature at z = 0, T_L is the temperature at z = L, L is the section of interest, and Pe is the Peclét number, defined as the ratio of convective to conductive heat flow

$$Pe = \frac{(\rho \cdot c)_w}{\lambda} \cdot L \cdot v_z \qquad (4)$$

where v_z is the vertical component of $\vec{v}$.

Integration of equation (1) with respect to z and evaluating the undetermined constant at z = 0 (where T = T_0) yields

$$\frac{\partial}{\partial z} T = \frac{Pe}{L} \cdot (T - T_0) + \left.\left|\frac{\partial}{\partial z} T\right|\right|_{z=0} \qquad (5)$$

For the other spatial components, x and y, the calculations are accordingly.

Therefore, determining Pe from the slope of a temperature gradient versus temperature plot (and

assuming a value for L) allows to relate thermal
measurements directly to fluid velocities with
equation (4).

The derived Darcy velocity is directly dependent on
5   the heat capacity of the fluid. The values for water and
oil are 4.0 kJ kg-1 K-1 and 1.8 kJ kg-1 K-1,
respectively. This means that for a certain Peclét number
the uncertainty for the derived Darcy velocity is ± 26%
if the water cut is not known. On the other hand, if the
10   flow rate is known the Peclét number can be used to
estimate the water cut.

The Peclét number analysis is only capable to provide
an estimate (limited to one-dimensional flow) of the flow
rate. Numerical modelling of coupled heat- and fluid-flow
15   and fitting the accuired data is a more appropriate
evaluation approach.

High-resolution temperature measurements over time
have been used in geothermal studies to quantify water
flow in the formation (assuming there is no flow in the
20   well during the measurement). Thermal recovery of a well
after drilling operations, which is equivalent to
monitoring the well temperature during shut-in after
production or heating, allowed to identify fractured
zones and characterize formation layers with different
25   permeability. The Peclét number analysis may be used to
derive natural flow velocities in the formation. Again,
temperatures may be measured after thermal equilibrium of
the well and in the absence of flow in the well. Any flow
in the well will dominate over the thermal signal from
30   the formation.

Some embodiments of the inventions also relate to a
method of producing crude oil from a subterranean
formation, wherein the influx of crude oil and/or other

fluids into the well is determined and/or adjusted to an optimal level on the basis of the method according to the invention.

Some embodiments of the inventions furthermore relate to heater and distributed temperature sensing (DTS) system suitable for use in the method according to the invention. The system comprises one or more mineral insulated heater cables, which each comprise an electrical conductor which is surrounded by a mineral insulation layer comprising an compacted mineral powder, which layer is enclosed in an annular metal sheath, and a fiber optical distributed temperature sensor which extends along at least a substantial part of the length of one or more mineral insulated heater cables.

Optionally at least one fiber optical distributed temperature (DTS) sensor extends through a channel extending through the mineral insulation layer of at least one of the mineral insulated heater cables.